Document 0016

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Ms. Ellen Russell
U.S. Department of Energy
Office of Fossil Energy, FE-27
1000 Independence Avenue, S.W.
Washington, DC 20485

July 30, 2004

Re: Comments on Draft Environmental Impact Statement for the Imperial-Mexicali 230-kV Transmission Lines (May 2004) (DOE/EIS-0365)

Dear Ms. Russell:

Sempra Energy Resources ("Sempra"), on behalf of Termoelectrica-US, LLC ("T-US"), the permittee for the existing transmission line from the Termoelectrica de Mexicali ("TDM") power plant in Mexico to the Imperial Valley substation, has reviewed the Draft Environmental Impact Statement ("DEIS") for the Imperial-Mexicali 230-kV transmission lines project and submits following additional information and comment on the DEIS to assist the decision maker in its consideration of the proposed action and its potential impacts.[1]

SER generally concurs with the analysis and findings contained in the DEIS and supports implementation of the proposed action and preferred alternative -- granting the Department of Energy ("DOE") Presidential Permit and Bureau of Land Management ("BLM") right-of-way to T-US. The DEIS complies with the requirements of the National Environmental Protection Act ("NEPA") and demonstrates that the environmental impacts in the United States associated with construction of the transmission line is *de minimus*. 0016-1

The DEIS also comprehensively evaluates the indirect and cumulative impacts on the United States[2] associated with TDM and InterGen La Rosita Power Complex operations in Mexico, and demonstrates that these impacts are likewise relatively minimal. 0016-2

[1] As you know, T-US is a wholly owned subsidiary of Sempra Energy Resources ("SER") who was the original applicant for the proposed Presidential Permit and right-of-way grant. T-US subsequently became the owner of the SER transmission line through an internal corporate reorganization of Sempra Energy, the corporate parent, and is now the permittee and applicant for the proposed action.

[2] The DEIS properly omits evaluation of impacts in Mexico. These impacts have already been evaluated by the permitting authorities in Mexico. Due to Mexican involvement in the environmental analysis and permitting of the power plants in Mexico consistent with Mexican law, neither NEPA nor Executive Order 12114 requires a duplicative assessment of environmental impacts within Mexico in the EIS for the proposed action.

0016-2 (cont.)

Permanent Removal of TDS

The DEIS includes a description of the proposed action including, among other things, an assessment of the amount of total dissolved solids ("TDS") removed by the TDM wastewater treatment plant, which is described and discussed in the DEIS at 2-33 to 2-34 and 4-19 to 4-20.[3] Additional detail regarding the TDS removal process is attached as Exhibit A to these comments. As shown in Exhibit A and in the DEIS, water balance calculations performed on the water treatment process demonstrate the removal of 3.7 million pounds per year of TDS when based on a 100% operations scenario. The DEIS assumes a 100% operations scenario because this generally results in a very conservative, worst case disclosure of potential impacts (in particular, with respect to air quality emissions and water flow reductions).[4]

However, with respect to TDS removal, it is also important to understand the expected TDS removal when analyzed based on an expected operations scenario. As explained in Exhibit A, with expected operations at TDM, 2.7 million pounds per year of TDS will be removed. Testing during actual operating experience verifies the removal of TDS and, in fact, demonstrates that actual removals are somewhat greater than what was conservatively calculated under the expected operations scenario in Exhibit A. Although the number of pounds of TDS actually removed by the water treatment plant will vary depending on the level of power plant operations, it is a substantial amount of TDS removal in any case. Along with the significant amount of dissolved organics, ammonia, phosphorous, and agricultural and industrial chemicals removed, operation of the wastewater treatment plant at the TDM project will have an overall beneficial impact on water quality in the New River and in the Salton Sea. 0016-3

Double Circuit Transmission Line

The DEIS (pages S-6, 1-6, and 2-15) also indicates that the transmission line for TDM is a double circuit, each with the capacity to carry the total output of the plant. The rationale for the double circuit is simply good engineering practices --- to enhance reliability of operation. Having two circuits capable of carrying the full output of the plant is typical of power plants that only have one link to the delivery point over long distances, nine miles in this case. This allows for maintenance of each circuit (insulators, conductors, etc.) without interruption in deliveries of electricity. In addition, each circuit terminates at different points at both the plant switchyard and the Imperial Valley substation. This allows for maintenance of yard equipment such as circuit breakers and switches, again without interruption of service to the grid. This feature is a 0016-4

[3] On Page 4-19, Section 4.2.4.1.2, there appears to be an error in the conversion of pounds to kilograms ("29 million and 14 million pounds" are incorrectly converted to "36 and 43 million kg", when the text should read "13 and 6.5 million kg"). 0016-5

[4] Of course, no power plant can ever operate 100% of the time 365 days a year in actual operations due to down time needed for scheduled maintenance, forced outages, and varying electricity demands.

benefit that can be achieved at very low cost as the cost of the added circuit is a very small component of the total cost of the transmission line. As explained in SER's letter to the Department of Energy dated April 7, 2004, SER is not currently developing a second power plant in the vicinity of the existing TDM facility. 0016-4 (cont.)

Alternatives and Mitigation Measures

The DEIS also evaluates a range of alternatives to the proposed action including an alternative that would grant the Presidential Permit only if the transmission lines were connected to a power plant that employed alternative cooling technologies such as dry cooling or wet-dry cooling.[5] The reason for using an alternative technology would be to reduce the amount of water necessary for cooling. For numerous reasons, however, these cooling alternatives would neither be feasible at TDM nor achieve a sufficient amount of water use reduction to justify the high cost and inefficiencies involved in retrofitting the plant to utilize such technology. In addition, the economic impacts to Mexico from loss revenue associated with water sales would also be significant.

First, dry cooling or wet-dry cooling technology is normally only used when sufficient water is not available for wet cooling and the economics of the project can withstand the increased cost and loss of performance caused by use of the dry cooling technologies. The use of dry-cooling alone or in parallel with wet-cooling for any portion of the operation at TDM means less electricity will be produced with the steam produced and thus more fuel per unit of electricity produced will be consumed, as explained in technical detail in Exhibit B hereto. How much less electricity will be produced depends on the ratio of dry cooling to wet cooling selected for the plant design. 0016-6 (cont.)

The detrimental performance effects of dry cooling would be especially pronounced at TDM because the daily mean maximum temperature exceeds 90°F for seven months of the year and 80°F for nine months of the year. These time periods coincide with the months of high electricity demand when the plant would be expected to operate the most hours and at its highest output level. Because of these harsh climate conditions, wet cooling is necessary for a majority of the year in order to maintain output and minimize impact on plant efficiency. In the current wet-cooled-only configuration, it is estimated that TDM uses approximately 70% of its annual amount of water during the warmer months.[6] This means that most of this water would still be

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[5] The DEIS also evaluates equipping the power plants with selective catalytic reduction ("SCR") technology and use of oxidizing catalysts on all gas turbines. The TDM plant was designed and built, and is operating with both SCR and oxidizing catalytic controls for NOx (2.5 ppm) and CO (4 ppm). The plant's Mexican environmental permits reflect this condition.

[6] The owners of TDM also own and operate a fully dry cooled power plant in Nevada, the El Dorado generating station. El Dorado is a smaller power plant because it does not have the amount of peak load duct firing (i.e. increased steam production and steam condensing cooling load) that TDM has. The annual consumption of water at El Dorado from cycle demands (no steam condensing) is 215 acre-feet. Using the same proportion, TDM cycle demands are estimated at 300 acre-feet alone. The estimated water

consumed in a wet-dry system and the reductions in water consumption from a wet-dry retrofit would be small and come at a very large cost, as discussed in more detail below.

Second, because the TDM plant is already completed, it would be extremely costly to retrofit the plant with wet-dry cooling technology. A description of the components of a retrofit similar to that designed for another SER facility under development in an arid region of the United States ('Project Alpha'), which would be capable of providing dry cooling for temperatures up to the 75°F to 80°F range, and preliminary estimate of its cost is included in Exhibit B. The extensive nature of the modifications and amount of new equipment would cost over $75 million. In addition, there would be significant costs associated with shutting down the facility for the 4-5 months necessary to complete the construction related to the retrofit.

If the wet-dry cooling system were required to provide dry-cooling up to ambient temperatures of 90°F (which could not be accomplished by the Project Alpha design), and wet cooling for temperatures above that, the size of the air-cooled condenser, according to equipment manufacturer information, would occupy an area of 6.5 acres, utilize 144 fans, consume 20 MW of power, and it would cost $80 million plus $40 million to install. *See* Exhibit B. These costs do not include the cost of the other extensive required modifications, which would likely add at least another $50 million based on the Project Alpha design estimate, or lost opportunity costs. There would also be significant air quality and noise issues associated with such an operation. 0016-6 (cont.)

Clearly, the capital costs for implementing any type of wet-dry cooling retrofit at TDM would be cost-prohibitive, in particular when there is sufficient water available to allow use of a much more efficient wet cooling system. In addition, water use impacts are minimal as documented in the DEIS.

Third, use of dry or wet-dry cooling at TDM would be inconsistent with the operation of the biological treatment component of the wastewater treatment plant, which must be operated at constant levels of flow to keep the microorganisms performing at optimal levels. Additional capital cost was incurred for the water treatment plant at TDM, however plant performance is not sacrificed. Operating this water treatment plant for long stretches of time while not using the water for cooling adds to the economic infeasibility of retrofitting TDM with dry or wet-dry cooling technology.

In any event, because the TDM power plant is located in Mexico, not in the United States, neither DOE nor BLM has any regulatory jurisdiction over the TDM power plant. The TDM plant is being operated in compliance with its Mexican-issued operating permit.[7] Adoption of any measure that purports to require alteration of the facilities and/or operations of a legally

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consumption of TDM with a wet cooled system under normal operation is 2,500 acre-feet per year, which means that 2,200 acre-feet are used in wet cooling for steam condensing.

[7] Although physically located in Mexico, the TDM plant is within the California Independent System Operator ("ISO") control area. This fact, however, does not make TDM any less of a Mexican facility and certainly does not turn it into a California facility. For example, other power plants located in Nevada are likewise included within the California ISO control area, however, those plants continue to be regulated under the laws of the jurisdiction (Nevada) in which the plant is physically located.

permitted power plant in another country would constitute improper and undue interference with the affairs of another country and should be rejected.[8] Thus, DOE and BLM should not include any additional conditions to the already existing permits. 0016-6 (cont.)

Air Quality and Health Impacts

With respect to the air quality analysis included in the DEIS, SER agrees with the approach used in the conformity analysis on DEIS pages 4-38 to 4-39. In particular, given the Supreme Court's recent decision in *U.S. Dept. of Transportation v. Public Citizen*, 124 S.Ct. 2204 (2004) and the lack of DOE or BLM regulatory authority over the power plants in Mexico, only emissions caused by construction and operation of the transmission lines should be considered in the conformity analysis. Moreover, even if the Imperial Valley were reclassified as a "serious" non-attainment area for PM10[9] resulting in an applicable exemption level of 70 tons/year, the proposed action with a maximum total of less than 12 tons of PM10 emissions per year would still be exempt from any additional conformity review.

The DEIS uses EPA-established significance levels ("SLs") as thresholds or yardsticks to assist the decision maker in judging the significance of potential adverse impacts of power plant emissions. We understand from the DEIS that the SLs are not being applied to emissions from the power plants as part of any direct application of the Clean Air Act ("CAA") Prevention of Significant Deterioration or EPA regulatory requirements to the plants. Because the power plants are located in Mexico and permitted under Mexican law, the United States has no authority to apply the CAA to the power plants or to designate areas in Mexico as "attainment" or "non-attainment;" such designations simply do not apply to areas outside the United States. Accordingly, it would not be appropriate for the DOE to directly apply CAA requirements (such as the requirement for offsets under CAA section 173(c)) to the power plants or attempt to regulate the power plants under the CAA through the conditioning of the transmission line permits. However, SER agrees that the EPA SLs can serve as a useful gauge of the significance of particular emissions and agrees with the DEIS' conclusions that comparing the emissions in the United States caused by the power plants with the SLs demonstrates that such impacts would 0016-7

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8 The TDM plant was designed and built with state-of-the-art emissions controls equivalent to those required in California and it is the cleanest gas-fired power plant in Mexico. While the DEIS properly discusses mitigation measures to assist in disclosing and understanding the potential environmental impacts of the proposed action, there is no legal requirement under NEPA to mitigate potential environmental impacts.

9 The Ninth Circuit Court of Appeals' order rejecting the claim that Imperial County's PM10 non-attainment was caused by emissions coming from Mexico into the United States and ordering that the Imperial Valley be reclassified as a "serious" non-attainment area for PM10 has evidently not yet occurred. *See Sierra Club v. U.S. Environmental Protection Agency*, 346 F.3d 955 (2003), *cert. denied* 124 S.Ct. 2873 (June 21, 2004); http://www.epa.gov/airprogm/oar/oaqps/greenbk/pnca.html#3471. Interestingly, the Court's finding with respect to the impacts of Mexican emissions on the Imperial Valley is consistent with the DEIS' finding (pages 4-52 to 4-54) that for much of the year (exceptions being June-August), the winds that transport air pollutants mainly blow from the United States into Mexico.

be minimal. This approach is also consistent with that utilized in the original Environmental Assessment prepared for the proposed action, which was upheld by the District Court. *See* DEIS Appendix A at A-25 to A-27, A-43 to A-44. 0016-7 (cont.)

We also concur with the DEIS analysis with respect to secondary PM10 formation from the power plant emissions. The DEIS correctly recognizes that an increase in the ammonia emission rate would not have a linear effect on the secondary ammonium nitrate concentration. The equilibrium relationship between ammonium nitrate formation and ammonia and nitric acid concentrations, illustrated on page 4-42 of the DEIS, is non-linear. In an ammonia-rich environment, increases in ammonium nitrate concentrations are less than proportional to increases in ammonia concentrations. In addition, as explained on pages 4-45 and 4-46, the analysis is extremely conservative because it assumes that the production of secondary ammonium nitrate from NOx emissions in the Imperial Valley is as efficient as in the cooler, more humid San Joaquin Valley, which is obviously not the case. 0016-8

Finally, SER agrees with the DEIS conclusion that the proposed action's O_3 and PM10 contributions would cause, at most, only a very minor increase in the asthma problem in Imperial Valley. Indeed, a quantitative analysis of the potential for increases in PM10 to cause increased asthma problems confirms this conclusion in the DEIS. *See* Exhibit C. As shown by the quantitative, conservative over-estimation of the impact, less than a single additional case of asthma hospitalization would be caused by power plant emissions assuming the power plants operated at 100% capacity 365 days a year. 0016-9

Thank you for the opportunity to comment on the DEIS.

Sincerely,

Enclosures

EXHIBIT A

TDM Water Treatment Plant ('WTP') Operation

The Water Treatment Plant at Termoelectrica De Mexicali consists of the following main components:

1. Biological Treatment Reactor and Secondary Clarifiers
2. DENSADEG^{TM} reactor
3. Demineralizer Plant
4. Press and Filter House
5. Waste Sump

The activity of each component can be summarized as follows:

1. *Biological Treatment Reactor and Secondary Clarifiers.* Water from the Zaragoza lagoons is introduced in this two-stage process block (aerobic and anaerobic environments) that uses biological treatment to oxidize organic matter and ammonia and to remove nitrates (formed as a result of oxidation of ammonia). Significant amounts of dissolved organics, ammonia and phosphorous compounds are removed in this Reactor, as well as agricultural and industrial chemicals. The Secondary Clarifiers separate the activated sludge from the water and recirculate the sludge to the biological reactor. A portion of the activated sludge is sent to the Press and Filter House (described below). Water balance calculations performed on this component of the treatment process show that for an incoming stream with a TDS concentration of 1,200 mg/l, the effluent displays a TDS concentration of 1,180 mg/l.

2. *DENSADEG^{TM} reactor.* This is a commercially available proprietary physical-chemical process, incorporating lime softening - clarification, that is accomplished in two tanks. The majority of the TDS removal accounted for in the DEIS occurs here (other reductions include those resulting from moisture in the sludge removed and cooling tower drift). In this stage, lime is added causing the precipitation of calcium and magnesium, thus removing much of the hardness, as well as substantial amounts of alkalinity, heavy metals and phosphate. The precipitated sludge is flocculated and separated from the water by sedimentation in the clarification process and sent to the Press and Filter House. The effluent flow, which is lower than the flow from the lagoons due to carryover in the sludge leaving this process, has concentrations calculated between 900 and 1,000 mg/l. After leaving the DENSADEG^{TM}, sulfuric acid and chlorine are added for pH control and disinfection, and the water is stored in the main service tank to be used in the fire protection system, the cooling tower, and the service water system.

3. *Demineralizer Plant.* To be used in the steam cycle, a very small portion of the water needs further purification. This is accomplished by filtering the water through sand and cartridge filters, a Reverse Osmosis System and an Electro-de-ionization System. As this plant operates in a closed cycle, the waste streams from these systems contain most of the dissolved solids that are removed. All of these waste streams are accounted for in the final balance.

4. *Press and Filter House.* All of the sludge streams (biological as well as lime softening sludge) are treated for water removal and converted into a nonhazardous solid waste that is disposed according to applicable Mexican laws. These materials are not reintroduced into the New River. Land disposal of these solids results in TDS reductions that benefit the New River.

5. *Waste Sump.* Waste streams are collected here for return to the drainage channels. Three streams collect here: (1) Cooling Tower basin, (2) Demineralizer Plant waste streams, and (3) Steam Cycle Blowdown. Assuming an 80% evaporation rate at the cooling tower, the TDS concentrations for each waste stream are: 4,504 mg/l for the Cooling Tower Basin (95%), 3,777 mg/l for the Demineralizer Plant (4%), and 5 mg/l for the Steam Cycle (1%). The combined effluent has a concentration of 4,430 mg/l.

As with any power plant, maintenance, forced outages such as those caused by equipment failure and market conditions, do not allow TDM to operate 100% of the time; however, the biological reactor should remain in operation to keep the microorganisms performing at optimum levels. As a result, when the plant is not producing electricity, the WTP operates in bypass mode and all the water obtained from the Zaragoza lagoons is treated in the Biological Reactor and Secondary Clarifiers and then returned to the drainage channels.

To calculate the amount of TDS removed, the difference in salt loading between the stream entering the plant and the stream being discharged into the drainage channels is calculated. Two modes of operation are considered:

1. '*Maximum Operation*' - TDM operates 100% of the time at full load.

2. '*Expected Operation*' - TDM operates 75% of the time. During this time, the plant operates at the average maximum load (600 MW) 40% of the time and at base load (500 MW) 60% of the time. When TDM is not in operation, the WTP is in bypass mode (25% of the time).

The following calculations were made to estimate the amount of TDS removed annually. The balances were run for each month of the year using typical weather data to determine the amount of water required. Evaporation at the cooling tower was fixed at 80%:

1. *Maximum Operation.*
   Total amount of water received by TDM is 4,372 acre-feet per year (@ 1,200 mg/l).
   Total amount evaporated is 3,497 acre-feet.
   Total amount discharged is 874 acre-feet (@ 4,430 mg/l).
   Total amount of TDS received is 6.5 million kg
   Total amount of TDS discharged is 4.8 million kg.
   Total amount removed is 1.7 million kg per year (3.7 million pounds).

2. *Expected Operation.*
   Total amount of water received by TDM is 3,794 acre-feet per year (@ 1,200 mg/l).
   Total amount evaporated is 2,503 acre-feet.
   Total amount discharged when producing electricity is 626 acre-feet (@ 4,430 mg/l).
   Total amount discharged when in bypass mode is 665 acre-feet (@1,180 mg/l).
   Total amount of TDS received is 5.6 million kg.
   Total amount of TDS discharged is 4.4 million kg (3.4 when producing electricity and 1.0 during bypass mode).
   Total amount removed is 1.2 million kg (1.18 when producing electricity and 0.02 during bypass mode) per year (2.7 million pounds).

It should be noted that when TDM is in bypass mode, in addition to the TDS removal benefits, all other benefits associated with running the Biological Reactor and Secondary Clarifiers are still being realized.

These calculations are based on water balance results for reductions of dissolved solids and were performed using an average raw water TDS of 1,200 mg/l. Estimated TDS concentrations in the treated water streams from the biological treatment system and the lime-softening process that were utilized were 1,180 mg/l and 1,000 mg/l, respectively.

Actual operating data has shown these numbers to be conservative. The TDM turnkey water treatment system contractor (Degremont de Mexico) took numerous conductivity readings for the raw water, biological treatment system effluent and lime softener effluent for a five-month period during startup. Conductivity (specific conductance) is an easy analytical method of measuring the conductive dissolved solids content (TDS) of water. Average conductivity readings for the three sample points were 1960 microS/cm, 1830 microS/cm, and 1600 microS/cm, respectively. Assuming that a conductivity value of 1960 microS/cm is equivalent to a TDS concentration of 1,200 mg/l, resultant TDS concentrations in the biological system and lime softener effluent streams would be 1,116 mg/l and 976 mg/l, respectively[1]. These are both below the calculated dissolved solids concentrations at these points of the process. Thus, not only does actual operating experience verify the removal of TDS, it also demonstrates that actual removals will be somewhat greater than what is conservatively calculated above for the Maximum and Expected Operation scenarios.

[1] 1960 microS/cm to 1,200 mg/l yields a reasonable TDS:conductivity ratio of 0.61, which falls comfortably in the range of industry-accepted values.

EXHIBIT B

Discussion of Wet-Dry Cooling and Retrofit to TDM

Background of Wet-Dry Cooling

In a combined cycle power plant like TDM, electricity is generated by two combustion turbines and by one steam turbine. In relatively simple terms, the process starts when burning natural gas in the combustion turbines that are attached to generators produces electricity. The exhaust of these turbines is very hot and is then used in a boiler to heat up water and produce steam. At TDM, additional heat can also be added by burning additional fuel in the boiler to produce more steam (duct firing). This steam, which is very hot and at very high pressures, is then sent to the steam turbine where more electricity is produced by the generator attached to the turbine. What drives the steam through the steam turbine is the difference in pressure between the inlet of the turbine and its exhaust. The greater the difference in pressure, the greater the amount of electricity produced. Therefore, since the inlet pressure is fixed, it is extremely important to have the lowest backpressure available at the exhaust of the steam turbine.

Cooling creates the backpressure of the steam turbine. When steam condenses vacuum is created (vapor takes up less room than water) and the pressure is actually lower than the atmospheric pressure. The lower the pressure, the greater the amount of electricity produced. In other words, good cooling is required to allow the maximum extraction of energy from the steam produced in the cycle.

In a wet cooled power plant, water is circulated through a shell and tube (water in the tubes and vapor in the shell) heat exchanger to condense the steam (i.e. wet-cooled) and then is cooled by an evaporative process in a cooling tower,. An alternative method for steam condensing is a direct air cooled condenser (i.e. dry-cooled) wherein the steam is condensed in tubes with air blown across them.

Lower backpressure, and thus higher steam turbine output, is always achieved with wet cooling at high ambient temperatures because the backpressure is determined by the cooling water temperature which, in turn, is determined by approach to the wet bulb air temperature. Conversely, the backpressure in the air cooled condenser is determined by approach to the dry bulb air temperature. Since wet bulb temperature is always lower than the dry bulb temperature, lower backpressures are always achieved with wet cooling for a given set of conditions than with dry cooling. Air-cooled condensing costs more and generally achieves less electrical production for a given amount of steam. If a power plant has large amounts of duct firing with resulting large amounts of steam produced, and is located in an area that experiences high temperatures year round, when dry cooling is used to maintain the same backpressure achieved by wet cooling, reductions in efficiency occur in the 10-15% range due to the power needed to run the air cooled condenser fans. . Because of this, air cooled condensing is only used when water is not available or site location conditions prevent evaporative cooling (generally due to cooling tower plume considerations).

The use of wet-dry cooling, usually designated as Parallel Condensing System (PCS), wherein an air-cooled condenser and a wet-cooled condenser are installed and operated in parallel, has only recently evolved as a primary design alternative to either wet cooling or dry cooling. The first units were developed as a result of necessity. For example, the Tucuman project in Argentina was converted during design of the facility when a determination was made in the middle of the project that not enough water was available. The Streeter station in Cedar Falls, Iowa is another example of a conversion to parallel condensing. However, this is an old, small plant, under 50 MW, which needed to be retrofitted to avoid winter icing of the highway from cooling tower drift. This highway was being constructed adjacent to the unit, and the Department of Transportation paid for the retrofit.

TDM's owners are considering wet-dry cooling technology for Project Alpha (still in the design phase) where only enough water can be obtained to maintain steam turbine performance during periods of peak demand and high ambient temperature.

Performance

The performance of an air cooled condenser (ACC) is dependent on the incoming steam temperature (measured at the exhaust of the steam turbine), steam flow and the ambient dry bulb temperature (the temperature indicated by a typical thermometer). The smaller the difference between the two temperatures (Inlet Temperature Difference, ITD) the bigger the air-cooled condenser must be for the same steam flow. The relationship between the ITD and the size of the ACC is logarithmic so that as the ITD becomes smaller (at high ambient conditions) the size of the ACC grows asymptotically to maintain performance.

The performance of a cooling tower and surface condenser or "wet cooling" is dependent on the incoming steam temperature and the wet bulb ambient temperature (wet bulb is a harder concept to explain, but in a very simplified way, one could say that it takes into account the cooling value of evaporation available). The primary reason cooling towers are always more effective than air-cooled condensers is that the ambient wet bulb is always lower than the ambient dry bulb, and therefore the ITD is always higher for a wet cooling system.

A parallel cooling system (PCS) improves the steam turbine output in comparison to dry cooling alone by adding a wet cooling component for periods of high dry bulb temperature.

Cooling is extremely important in a power plant because the better the cooling the lower the backpressure that the steam turbine works against. With low backpressure values, more energy can be extracted from the steam turbine to produce electricity in the generator. A steam turbine can lose up to 8 MW for every inch (HgA) of increased backpressure.

In addressing the feasibility of a wet-dry system for TDM, a preliminary check was made of requirements to maintain a 2"HgA backpressure up to a temperature of 90°F dry bulb ambient temperature at base load conditions at TDM. Wet cooling would be activated above this ambient temperature. According to Marley Cooling Technologies, Inc., a well-respected manufacturer of

cooling systems for power plants, the plant would require an air-cooled condenser consisting of 144 modules or fans in a 24x6 arrangement. The structure would be 1,035 ft wide, 273 ft long and 230 ft high (an area of approximately 6.5 acres). The power required to run the fans would be 20,100 kW and the unit alone would cost roughly $80 million plus the cost to erect the unit, which could be as high as $40 million. These costs do not include other retrofit costs required to integrate this air cooled condenser into the TDM facility. In addition, noise and particulate emissions from operation of the air cooled condenser fans would be significant. Clearly a dry cooling system to match the performance of the wet cooling system at base load and 90°F is not practical. In other words, a wet-dry cooling system that would work 100% on dry cooling up to 90°F and on wet cooling for temperatures above that is not feasible for TDM.

Although a PCS can improve steam turbine output at high dry bulb temperatures when compared with dry cooling alone, the output is still less than a wet cooling plant for high ambient conditions. The auxiliary load from the parallel system is also higher than for a wet cooled plant. The performance limits of a PCS is between the performance of a dry cooled plant and a wet cooled plant, and depends on the percentage of wet cooling that is selected.

Retrofit Issues

Given the impracticality of using an air cooled condenser to provide 100% dry cooling up to 90°F at TDM, a preliminary estimate was also made for retrofitting TDM with a more reasonably sized PCS similar to what is being considered for Project Alpha and the cost was estimated to be more than $75 million. It is expected that such a retrofit would allow TDM to operate in dry cooling mode in temperatures up to the 75-80°F range. A description of the necessary modifications and an estimate of cost and schedule are set forth below under the heading 'RETROFIT OF TDM TO "PROJECT ALPHA" DESIGN'.

One additional concern is that the application of a PCS presents a particular operations problem for the TDM plant due to the nature of the raw water pretreatment system on site. This process treats water intercepted at the discharge of Mexicali's sewage treatment lagoons. There are significant operational limitations regarding the ability of the pretreatment plant to change process load quickly or to start up and shut down. The continuous flow for make up water for a cooling tower is manageable but the wet cooling portion of a PCS is expected to be cycled on and off seasonally and daily which is not consistent with the operation of TDM's water treatment plant. Turndown is slow and difficult and if shut down, startup and re-establishment of the biological treatment process takes several weeks.

Water Consumption

Even full dry cooling plants consume water. The annual consumption of water at El Dorado Energy, a fully dry cooled plant in Nevada is 70 million gallons of water (215 acre-feet) for steam cycle makeup and gas turbine air inlet evaporative cooling. There is no water used for cooling/condensing steam from the turbine at El Dorado. El Dorado is a smaller plant than TDM as it has a much smaller amount of duct fired steam production for peaking operation. If TDM were to be 100% dry cooled, TDM's water use would be higher than El Dorado due to the higher level of duct firing. It is estimated that for cycle demands alone, TDM would use approximately 300 acre-ft annually.

The amount of water consumed by a cooling tower in a PCS is dependent on the level of wet cooling used. The dry bulb temperature at the TDM site exceeds 100°F Fahrenheit for more than 100 days per year. For 7 months of the year, the daily mean maximum temperature exceeds 90°F. For 9 months of the year, the daily mean maximum temperature exceeds 80°F. These months also coincide with the peak demand periods for electricity when TDM is expected to be operated more hours and at higher output. It is clear from the basic climate at TDM that a significant amount of water cooling is required for a large portion of the year to maintain performance at TDM.

Conclusions

It is not practical to retrofit the TDM project to use a PCS because of the following factors:

1. High capital cost (over $75 million).
2. Lost opportunity cost from the outage required for the retrofit (5 months of no production).
3. Increased operating costs from running auxiliary equipment and lower efficiency of cooling system.
4. Minimal water savings to maintain performance as close to the performance with a wet-cooled system due to climate conditions at the TDM site.
5. Operational difficulties in regard to the water treatment plant.

RETROFIT OF TDM TO "PROJECT ALPHA" DESIGN

Project Scope
An engineering study would need to be performed to review the interfaces with the existing infrastructure at TDM. Many systems throughout the plant would be affected and the following work is anticipated to be required with regard to the following systems:

Circulating Water
The condenser for the PCS would be smaller in capacity than the current one and sited at a new location further from the cooling tower than the existing unit. New circulating water piping would have to be installed to the new condenser and interfaced with the existing piping. The new circulating water system needs to be characterized so that the system pumping curve can be compared with the pump curves for the existing circulating water pumps to determine the impact. Any reduction in flow due to a higher pumping head from the PCS will most likely be acceptable due to the reduced load on the cooling tower.

Condensate
The condensate for the PCS would have to be collected at a location far removed from the existing location. This requires a new condensate system to be designed and constructed so that

the system characteristics at the interface with the existing condensate pump discharge piping are equivalent. This will require a new set of pumps controls, piping, instrumentation and DCS according modifications. A new make up water line will also be required.

Dearation
The TDM project currently employs a dearating condenser for the removal of dissolved oxygen. The PCS requires the use of an integral dearator on the HRSG low pressure steam drums or a remote dearator. Incorporation of integral dearators on the existing boilers is not expected to be practical so a remote dearator would have to be installed. Sources and interfaces with continuous and pegging dearating steam would be required and the additional modifications required achieving this.

Chemical Feed
A new chemical feed program would need to be developed for the PCS to accommodate the impacts of the air cooled condenser on the condensate chemistry and the specific characteristics of the PCS. The condensate chemical feed system would be located adjacent to the condensate tank and PCS condenser hotwell. Additional modifications would need to be made to the existing sampling panel system for condensate.

Closed Cycle Cooling Water
The heat rejection for the closed cycle cooling water system would still be accomplished by the cooling tower but by using the auxiliary cooling pump during dry cooled operations. The auxiliary cooling water pump was originally intended for use only during times when the plant was shut down but cooling was still required for this system. An entire spare pump would need to be purchased to provide a level of availability consistent with the existing use.

Air Removal System
The existing air removal system at TDM is a set of liquid ring vacuum pumps. The large internal volume of air-cooled condensers requires a steam jet air ejection system for hogging and continuous air removal during operations. The existing steam system would have to be modified to support the steam jet air ejection system.

Controls
A significant modification to the distributed control system would need to be engineered and implemented including new graphics, logic programming, digital and analog data points and potentially system cards. A new cabinet would probably be installed within an MCC building associated with the PCS with a fiber connection to the control room.

Electrical
The PCS and other plant modifications would impact the plant electrical system significantly. It is likely that the entire auxiliary electrical system including the plant 4160V bus and the auxiliary transformers would require significant modifications. The transformers would most likely need to be replaced, as they are not sized for the increased auxiliary load for running the PCS as well as other increases in auxiliary load from the CCCW and condensate systems. The modifications to the 4160 V switchgear are expected to be extensive.

Additionally, new 4160/480 V transformers and 480V MCCs would be required to support the PCS with associated duct bank and electrical trays.

Engineering, Procurement & Construction
A design/construction contract would be required to complete the retrofit based on the following expected scope.

- PCS
    - Air-Cooled Condenser
    - Steam Duct
    - Steam Turbine Expansion Joint
    - Surface Condenser
    - Condensate Tank
    - Air Removal System
- All New Electrical Systems, Duct Bank & Cable Tray
- New Circulating Water Pipe
- New Condensate System Including Chemical Feed
- Spare Auxiliary Cooling Water Pump
- All Mechanical Retrofits As Required For PCS Integration
- Remote Dearator Installation & Retrofit
- All DCS Retrofits Required
- New Access Roads
- Disposal Of All Discarded Equipment

Schedule
The engineering study would take approximately five months to complete at which time a request for proposals could be developed. Another four months would be required to assemble a contract and detailed specifications for the work to be completed, bid and select a contractor. Another two months would be required to issue a full notice to proceed to the contractor for detailed engineering to begin.

Major equipment deliveries are expected to require up to 21 months.

Even though a good portion of the construction work can be performed while the plant is running a significant outage would be required for the following work:

- Removal Of Old Condenser and Steam Duct Connection
- Mechanical Integration Of Condensate & CCCW Systems
- Electrical Modifications
- Circulating Water Piping Modifications
- DCS Modifications
- HRSG Modifications
- Steam System Modifications (Air Removal & Dearation)
- Start Up & Commissioning

The estimated duration of the outage is 120-150 days depending on the results of the detailed engineering study. This assumes two shifts working six days per week.

It is anticipated that a retrofit of the TDM project would require approximately three years.

Cost
A budgetary estimate has been generated for retrofitting TDM with a PCS approximately the size of Project Alpha:

	Thousand $
Initial Engineering Study	$500
PCS Equipment	$30,000
Electrical Retrofit	$7,000
Circulating Water Retrofit	$1,300
Condensate System Retrofit	$1,100
Mechanical Retrofit	$1,800
Dearator Retrofit	$1,500
Controls Retrofit	$1,500
Civil Works	$1,000
Detailed Engineering & Procurement	$3,000
Construction Management, Labor & Equipment	$25,000
Contingency	$2,500
Other Costs (Consulting/SER Internal/Legal)	$500
TOTAL	**$76,700**

In addition, there would be lost opportunity costs from the loss of electricity production during the outage that would be required to install the system. This additional cost needs to be estimated and added to the total cost of retrofitting TDM with a PCS.

ENSR INTERNATIONAL

EXHIBIT C

Memorandum

To:	Alberto Abreu/Octavio Simoes Sempra Energy Resources	**Date:**	July 27, 2004
From:	Steven Heisler	**File:**	06205-042-100
RE:	DEIS for the Imperial-Mexicali 230-kV Transmission Line project	**CC:**	Sara Head

At your request, we have reviewed the Draft Environmental Impact Statement (DEIS) prepared by the U.S. Department of Energy and U.S. Department of the Interior dated May 2004 for the Imperial-Mexicali 230-kV Transmission Line project with respect to health impacts and provide the following comments.

PM10 Impacts on Asthma Hospitalizations

Page 4-98 of the DEIS states that "The high incidence of asthma is a particular concern in Imperial County. O_3 and PM in the region are likely to be contributing factors. However, the operation of the TDM plant and the EBC and EAX export units at the LRPC plant would contribute only very minor increases to the O_3 and PM levels in the region, and thus would contribute at most a very small increase in the asthma problem ..." We agree with this statement. However, the DEIS does not provide a quantitative estimate of the potential impacts of PM10 emissions from the power plants on the asthma problem.

We have developed the following conservative estimate of the potential increase in asthma hospitalizations in Calexico that might be caused by PM10 emissions from the power plants. Dr. Paul English[1] stated that Pope and Dockery[2] reported that analyses of epidemiological data found that a 10 $\mu g/m^3$ increase in PM10 concentrations is associated with a three percent increase upper respiratory symptoms and asthma. Assuming, as Dr. English did, that the increase in asthma is proportional to the increase in PM10 concentrations, the 2.45 $\mu g/m^3$ maximum modeled increase in 24-hour average

[1] June 16, 2003 Supplemental Declaration of Paul Brian English, Ph.D., in Support of Plaintiff's Request for Permanent Relief, Case No. 02-CV-513-IEG (POR)

[2] Pope, CD, and Dockery, DW, 1999. Epidemiology of Particle Effects. In: Air Pollution and Health. Holgate, S; Samet, J; Koren, J; and Maynard, RL, eds. Academic Press, London.

ENSR INTERNATIONAL

PM10 concentrations from emissions from the TDM and LRPC export turbines could cause a 0.74 percent increase in asthma hospitalizations, and an increase as large as the 5 $\mu g/m^3$ significance level could cause a 1.5 percent increase in asthma hospitalizations.

The California Department of Health Services (DHS) reported that the age-adjusted annual asthma hospitalization rate in Imperial County from 1998 through 2000 was 19.56 per 10,000 population for all ages and was 52.43 per 10,000 for children ages 0-14.[3] The population of Calexico during 2000 was 27,109, and population between ages 0 and 14 was 7,727.[4] Thus, the annual number of asthma hospitalizations between 1998 and 2000 is estimated to be 53 for the entire population (19.56 per 10,000 x 27,109 / 10,000) and about 41 for children aged 0-14.

If the power plant emissions caused an increase of 0.74 percent in the asthma hospitalization rate, which corresponds to the maximum modeled 24-hour average PM10 impact, the total annual number of asthma hospitalizations for all ages would increase by 0.4 (0.74 percent increase x 53 / 100), and the annual number for children ages 0-14 would increase by 0.3 (0.74 percent increase x 41 / 100). Thus, there would be less than one additional asthma hospitalization per year caused by emissions from the power plants. This is a conservatively high estimate because it assumes that the maximum modeled 24-hour average PM10 impact would occur every day throughout the entire City of Calexico when, in fact, it would only occur at a single location (the point of maximum modeled impact) on a single day.

Additionally, If the power plant emissions caused an increase of 1.5 percent in the asthma hospitalization rate, which corresponds to the 5 $\mu g/m^3$ 24-hour average PM10 significance level, the total annual number of asthma hospitalizations for all ages would increase by 0.8 (1.5 percent increase x 53 / 100), and the annual number for children ages 0-14 would increase by 0.6 (1.5 percent x 41 / 100). Thus, there would be less than one additional asthma hospitalization in Calexico per year, even if impacts caused by emissions from the power plants were as high as the significance level. Again, this is a conservatively high estimate because it assumes that the impacts would be equal to the significance level every day throughout the entire City of Calexico when, in fact, it would only occur at a single location on a single day.

These conservative estimates of potential increases in asthma hospitalizations in Calexico demonstrate that, as concluded in the DEIS, emissions from the power plants would contribute at most a very small increase in the asthma problem.

[3] Stockman JK, Shaikh N, Von Behren J, Bembom O, Kreutzer R. California County Asthma Hospitalization Chart Book: Data from 1998-2000. Oakland, CA: California Department of Health Services, Environmental Health Investigations Branch, September 2003.

[4] http://calexico.areaconnect.com/statistics.htm

Document 0017

INTERNATIONAL BOUNDARY AND WATER COMMISSION
UNITED STATES AND MEXICO

OFFICE OF THE COMMISSIONER
UNITED STATES SECTION

JUL 30 2004

Ms. Ellen Russell
U.S. Department of Energy
Office of Fossil Energy
Mail Code FE-27
1000 Independence Avenue, SW
Washington D.C. 20585-0301

Re: Draft Environmental Impact Statement for the Imperial-Mexicali 230-kV Transmission Lines (DOE/EIS-0365), Presidential Permits, Baja California Power, Inc. and Sempra Energy Resources

Dear Ms. Russell:

The United States Section of the International Boundary and Water Commission (USIBWC) appreciates the opportunity to review and comment on the Draft Environmental Impact Statement (DEIS) for the Imperial-Mexicali 230 kV Transmission Lines (DOE/EIS-0365) provided with your May 6, 2004 letter. The DEIS was prepared from the viewpoint that the transmission lines were not constructed. We offer the following comments from the same viewpoint for the proposed action.

The USIBWC understands that the proposed project is for the construction and operation of two parallel electrical transmission lines in California and Baja California which will provide electrical service to customers in the southwestern United States and northern Mexico. We understand that the project proponents, Baja California Power, Inc. (BCP) and Sempra Energy Resources (SER), are seeking authorization to construct, operate, and maintain electrical transmission facilities in both the United States and Mexico to import electrical energy to southern California. Though the routing of these lines is parallel, each company is independently seeking the required approvals for its respective project and is requesting a Presidential Permit for works which cross the international boundary. Each of the new systems will have the capacity to carry 230 kilovolts (kV) from proposed power generation facilities in Mexicali, Baja California to the Imperial Valley Substation. Each proposed project includes the construction and operation of approximately 6 miles of transmission line in the United States and 3 miles in Mexico.

The USIBWC has a duty to access, maintain, and utilize the international boundary monuments along the United States/Mexico international land boundary. The USIBWC is charged with these duties through treaties and international agreements between the United States and Mexico. We require that the proposed works, related facilities, and related facilities associated with the BCP and SER electrical transmission lines (i.e. laterals, overhead and buried electrical power transmission lines, pipelines, and new power plants) not affect the permanence (disturb the foundations) of

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existing boundary monuments nor impede access for their maintenance. The USIBWC requires that all structures be off-set from the international boundary by a minimum of two feet, maintain a clear line-of-sight between affected boundary monuments, and maintain a 10-foot off-set around each boundary monument.

Proposed construction activities should not change historic surface runoff characteristics at the international border. This requirement is intended to ensure that development in one country will not cause damage to lands or resources in the other country. Engineering drawings and supporting calculations, which demonstrate the proposed activities and construction will not change historic surface runoff characteristics, must be provided for review and approval prior to beginning work. The proponent must properly maintain structures constructed along the international boundary and address any liability issues related to the proposed activities.

The USIBWC requires that final engineering drawings be submitted to the USIBWC for review and approval prior to beginning the proposed electrical transmission line and related facilities construction. These drawings must show the location of each component in relation to the international boundary and the boundary monuments. Plans for construction should be submitted to the USIBWC as soon as possible. 0017-1

Project information including plans should also be submitted to the Mexican Section of the International Boundary and Water Commission in Ciudad Juarez, Chihuahua, Mexico by project proponents in Mexico. The proponent should verify that coordination with proper authorities in Mexico is complete prior to construction. The USIBWC may verify that proper coordination with Mexico is complete. Proposed projects in Mexico must be reviewed by the appropriate agencies in Mexico and be constructed in accordance with Mexican laws.

On page 5-9 of the DEIS the discussion of the Total Maximum Daily Load program the last sentence should state "discharging to the watershed within California." Water quality criteria for discharges to the New River in Mexico are established by legislation in force in that country. 0017-2

On page 5-14 the DEIS indicates the primary purpose of the proposed projects is to transfer electrical energy from new natural gas-fired electric power generation plants to the power grids in southern California. The proposed power plant projects in Mexico will involve the construction and operation of wastewater treatment plants which discharge effluent for use in the facility cooling system. Those cooling systems discharge to drainages that flow to the New River in Mexico. The original Environmental Assessment (EA) considered transboundary impacts to air quality but did not consider transboundary impacts to water quality. The DEIS has defined the construction and operation of the related power plant projects and wastewater plants in Mexico as within the region of influence and as reasonably foreseeable actions. The USIBWC concurs with this approach. Air quality impacts to the Salton Sea Air basin were evaluated. Impacts to water quality in the New River and Salton Sea were evaluated. 0017-3

The prior EA discussed the cooperative efforts of the United States and Mexico through the International Boundary and Water Commission (IBWC), in Minute Nos. 261, 264 and 294 to address water quality concerns for the New River. The DEIS does include this discussion. Under Minute

No. 264, Mexico has the obligation to ensure that flows in the New River meet established water quality standards at the international boundary. The proponent should evaluate the impact of the cooling system discharges on efforts by agencies in Mexico to comply with these New River water quality standards at the international boundary. 0017-3 (cont.)

Thank you for the opportunity to provide comments on the proposed projects. Please continue keeping us informed of the presidential permit process, and submit related information, public meeting notices, to my attention, and provide copies to our Yuma Project Manager, Mr. Al Goff, at P.O. Box 5737, Yuma, Arizona 85364, and our San Ysidro Project Manager, Mr. Dion McMicheaux, at 2225 Diary Mart Road, San Ysidro, California 92173. If you have any questions regarding this information, please call me at (915) 832-4740.

Sincerely,

Sylvia A. Waggoner

Sylvia A. Waggoner
Division Engineer
Environmental Management Division

CC:

Mr. Stephen J. Gallogly, Director
International Energy and Commodities Policy
U.S. Department of State
Washington, DC 20520

Mr. Dennis Linskey
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CC electronically to:

Ellen Russell, NEPA Document Management
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Document 0018

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July 30, 2004

By Electronic Mail and Overnight Delivery

Ellen Russell
Office of Fossil Energy (FE-27)
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-0350
(202) 586-9624

Re: Draft EIS for the Imperial - Mexicali 230-kV Transmission Lines

Dear Ms. Russell:

Enclosed please the comments of Baja California Power, Inc., ("BCP") on the Draft Environmental Impact Statement for the Imperial - Mexicali 230-kV Transmission Lines. If you have any questions, please contact Sean Kiernan of InterGen at (781) 993-3037.

Thank you for your consideration of BCP's comments.

Sincerely,

Eric J. Murdock

Eric J. Murdock
Counsel for Baja California Power, Inc.

Enclosures

ATLANTA AUSTIN BANGKOK BRUSSELS CHARLOTTE DALLAS HONG KONG KNOXVILLE
LONDON MCLEAN MIAMI NEW YORK NORFOLK RALEIGH RICHMOND SINGAPORE WASHINGTON
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Comments of Baja California Power, Inc.,
on the Draft Environmental Impact Statement
For the Imperial - Mexicali 230-kv Transmission Lines

July 30, 2004

A. Introduction

Baja California Power, Inc., ("BCP") appreciates the opportunity to comment on the Draft Environmental Impact Statement ("DEIS") for the Imperial-Mexicali 230-kv Transmission Lines. BCP is the developer of one of the two transmission line projects that are the subject of the DEIS. As described in the DEIS, the BCP transmission line runs from the Imperial Valley substation to the U.S.-Mexico border where it connects to another transmission line extending south from the border to the La Rosita Power Complex ("LRPC").[1] BCP has worked cooperatively with the U.S. Department of Energy and the Bureau of Land Management (together, the "Agencies") to provide factual information regarding its transmission line project, as well as the configuration and operation of the LRPC, and looks forward cooperating further with the Agencies as appropriate to complete the final EIS.

Overall, BCP believes the DEIS presents a thorough and well-documented description and analysis of the environmental impacts associated with the transmission line projects. As is to be expected with any document of this length and complexity, the DEIS contains a few minor errors of fact and analysis. None of these errors materially affects the overall conclusions of the DEIS. Nonetheless, in the interest of accuracy and completeness, they should be corrected in the final EIS. The necessary corrections and clarifications are set forth in Appendix A to these comments.

[1] As also described in the DEIS, the LRPC consists of two separate power plants -- one owned and operated by Energia Azteca X ("EAX") and one owned and operated by Energia de Baja California ("EBC"). BCP, EAX, and EBC are corporate affiliates of InterGen.

There are also a few more significant issues that should be addressed in the final EIS. Most important, the discussion of environmental impacts should be revised to distinguish more accurately between environmental impacts properly attributable to the BCP transmission line and those that represent baseline environmental conditions. In particular, the presentation of impacts related to the "proposed action" should not include the export turbine at EAX plant, which would operate even in the absence of the BCP line. Rather, the EAX plant should be addressed, along with other existing and reasonably foreseeable sources, as part of the analysis of cumulative impacts. In addition, the final EIS should acknowledge more prominently the overall conservatism of the methodology used to estimate and evaluate environmental impacts from the transmission line projects, and in some cases a more realistic approach may be warranted. Finally, the discussion of the "technology" and "mitigation" alternatives with respect to power plant impacts should focus only on impacts from the BCP and TDM plants, and should include a more rigorous analysis of the technical feasibility and cost-effectiveness of these alternatives. It also should take into account mitigation measures already being implemented.

B. The analysis of environmental impacts should distinguish more accurately between project-related effects and baseline environmental conditions.

The DEIS defines the "no action" alternative as the denial of both of the transmission line permit applications, and states that "[u]nder the no action alternative, neither of the proposed transmission lines would be constructed and the environmental impacts associated 0018-1
with their construction and operation would not occur." DEIS at 2-1. Accordingly, the power plant impacts associated with the no action alternative should be zero. However, the DEIS presents the impacts associated with the no action alternative as those resulting from the operation of the three turbines at the EAX plant. See DEIS, Sections 4.2.3 and 4.3.3 and

2

Tables 4.2-1 and 4.3-1b. It appears that the DEIS takes this approach based on the fact that all three of the gas turbines at the EAX plant would operate even if the BCP transmission line permit were denied. See DEIS at 2-1. This fact does not justify singling out the EAX plant impacts as the no action scenario. There is no logical basis to treat the EAX plant any differently from any other existing power plant, industrial facility, or other source whose impacts comprise the baseline environmental conditions against which the project-related impacts are to be assessed. The impacts from the EAX plant are more properly addressed as part of the cumulative impacts analysis, along with the impacts from other existing and reasonably foreseeable sources.

The DEIS defines the proposed action as the issuance of Presidential permits for both of the transmission lines on the terms proposed by the applicants, and states that "[t]he impacts attributable to the preferred alternative would be those associated with the operation of the entire TDM plant, the EBC unit, and the EAX export unit, and the construction and operation of the proposed transmission lines." DEIS at 2-2. As the DEIS otherwise acknowledges, and as the district court expressly found, the EAX export turbine (as well as the other two EAX turbines) would have been built and would operate even if the BCP transmission line were never constructed or permitted. The DEIS nonetheless includes the EAX export turbine in its analysis of impacts attributable to the proposed action simply because the BCP line, if it is available, would be used to transmit at least a portion of the output from the EAX export turbine to the U.S. See id. This is not a valid basis for attributing the impacts from the operation of the EAX export turbine to the BCP transmission line. Under NEPA, an effect may be attributed to an action only if is "caused by" the action. See 40 C.F.R. § 1508.8(a), (b) (definitions of "direct" and "indirect" effects). The EAX export unit was not "caused by" the

0018-1 (cont.)

BCP line. The export turbine was part of the EAX plant design prior to any plans to build the BCP transmission line and unquestionably would be operated even in the absence of the BCP line. By including the EAX export unit in its analysis of impacts attributable to the BCP transmission line, the DEIS overstates the true impacts by a factor of two.[2]

This is not to say that the DEIS should not consider the impacts from all of the units at the LRPC. However, it is not appropriate, even for the sake of conservatism, to present the impacts of the proposed BCP line as the combined impacts from the EBC plant and the EAX export unit. This approach is misleading in at least two respects. First, it double counts the operations of the EAX export unit by including that unit under both the no action alternative and the proposed action alternative. More importantly, it largely fails to consider any scenario that is properly focused on impacts from just the proposed action -- i.e., the operation of the EBC plant alone or in combination with the operation of the TDM plant. None of the summary tables in Sections 4.2 and 4.3 present data under either of these two scenarios -- even though these are the scenarios that properly reflect the impacts from the proposed action. The final EIS should clearly distinguish genuine project-related impacts from impacts that form part of the baseline for the cumulative impacts analysis so the public and the decision-makers at DOE and BLM can understand the true environmental consequences of the permitting action under consideration. In particular, the summary tables in Sections 4.2 and 4.3 (and the corresponding

0018-1 (cont.)

[2] The recent decision of the U.S. Supreme Court in Department of Transportation v. Public Citizen, 541 U.S. __, Slip. Op. at 12-13 (June 7, 2004), makes clear that there must be a "reasonably close causal relation" between an agency action and an environmental effect, not just a "but for" causal relationship, before that effect is properly attributable to the action for purposes of NEPA analysis.

text) should be revised to include separate columns (and discussion) to present the relevant data for the EBC plant operating alone and the EBC plant operating together with the TDM plant.[3] 0018-1 (cont.)

C. The DEIS generally overstates the true magnitude and significance of environmental impacts attributable to the BCP transmission line project.

1. Magnitude of Power Plant Impacts

The DEIS contains numerous estimates and projections regarding impacts to the environment from the proposed actions -- in particular with respect to water use and air emissions from the new power plants in Mexico to which the transmission lines are connected. In nearly every instance, these figures are based on conservative assumptions. In some cases, the approach taken in the DEIS is overly conservative – to the point of misleading the reader -- and more realistic assumptions should be used in the final EIS. More generally, while the use of conservative assumptions is not necessarily inappropriate for many of the specific analyses of environmental impacts, the final EIS should make sure that readers of the document understand the extent of the conservatism built into that analysis, and point out that this approach likely overstates the actual environmental impacts of the transmission line projects. 0018-2

The follow is a listing of the more significant examples of conservatism underlying the analysis presented in the DEIS:

a. Capacity Factor. The power plant impacts described in the DEIS assume that the plants will operate at 100% capacity factor -- i.e., 24 hours a day, 7 days a week. In fact, no power plant operates at 100% capacity factor over the course of an entire year. At a 0018-3

[3] Attached as Appendix B to these comments are revised versions of the pertinent tables from Section 4.2 of the DEIS showing water quality data for these two "proposed action" scenarios. Because we did not have access to the data underlying the air modeling results presented in the DEIS, we were not in a position to prepare similar tables breaking out the modeled impacts associated with emissions from the EBC and TDM plants. Nonetheless, the final EIS should present the modeling results for the EBC and TDM plants operating individually and together.

minimum, periods of downtime must be scheduled for regular maintenance. In addition, there may be unexpected outages, and there may be periods where demand is not sufficient to call the unit into operation. For the LRPC, it is expected that the actual capacity factor will be on the order of 60%. As a result, all of the figures reported in the DEIS for the LRPC regarding total annual air emissions and water consumption are overstated across the board by approximately 40%.[4] 0018-3 (cont.)

b. Displacement Effects. The La Rosita and TDM plants are clean facilities with state of the art emissions controls. The air emissions from these facilities are lower than 70% of all power generating facilities serving the California grid (including most of the existing generating facilities located in Imperial County). When these plants are in operation, they very likely are displacing generating facilities whose emissions per megawatt-hour produced are significantly higher. The DEIS does not take into account these relative emission reductions resulting from the operation of the La Rosita and TDM plants. Although it is difficult to identify the specific facilities displaced by the Mexico plants, or to quantify the environmental impacts avoided as a result of such displacement, conceptually such avoided impacts offset at least in part the impacts from the operation of the Mexican power plants. 0018-4

c. Direct Particulate Emissions. The air quality analysis in the DEIS is based on an emission rate for fine particulates ("PM_{10}") of 52.3 pounds per hour for each 0018-5

[4] By the same token, the beneficial effects of wastewater treatment at the LRPC are likely somewhat overstated in the DEIS because they likewise are based on the assumption of water use -- and thus water treatment -- at a capacity factor of 100%. To the extent that the plants actually run less than 100% of the time, less water may be treated, and some of the secondary and tertiary treatment processes may be by-passed. However, although it may be possible to reduce the flow to the biological treatment plant somewhat during periods of reduced plant demand for water, the treatment plant must maintain a minimum flow at all times in order to sustain the biological processes and to be in a position to supply sufficient quantities treated water on short notice when the turbines are called into operation.

turbine at the LRPC. See DEIS, Appendix G-1. This emission rate was reflects the guarantees provided by the turbine vendor. Vendor guarantees for PM_{10} from gas-fired turbines are generally much higher than the actual emission rates to account for the limitations of the compliance testing methodologies -- which often produce significant variability in test results that is not representative of actual emissions. See Memorandum from Gary Rubenstein to Sean Kiernan, July 29, 2004, ("Rubenstein Memo") at 2.[5] Studies of test data from gas turbines comparable to those at the LRPC demonstrate that actual PM_{10} emissions from these units are on the order of 5 lbs/hr or less, with very little variability. Id. at 4-5. The actual annual emissions of PM_{10} from the EBC plant therefore are likely closer to 22 tons per year (even assuming a capacity factor of 100%), rather than the 238 ton per year figure presented in the DEIS. As a result, the air quality modeling results reported in the DEIS significantly overstate the actual effects of plant emissions on ambient concentrations of PM_{10}. 0018-5 (cont.)

d. Formation of Secondary Particulates. To estimate the impacts from the formation of secondary particulates attributable to emissions from the power plants, the DEIS uses a conversion factor of 0.6 grams of NH_4NO_3 for each gram of nitrogen oxides. DEIS at 4-44. The 0.6 value is taken from a study by Stockwell of conditions in the San Joaquin Valley, where humidity – a critical factor in the formation of secondary particulates – is much higher than in the Imperial Valley. As a result, this conversion factor is overly conservative, and results in what the DEIS itself characterizes as a "gross overestimate." The DEIS acknowledges that a study specific to the Imperial Valley-Mexicali area (Chow and Watson) concludes that the ambient concentration of secondary particulates attributable to all sources is no more than 2 to 3 ug/m^3 for 24-hour measurements. Emissions from the power plants 0018-6

[5] A copy of the Rubenstein Memo is attached to these comments as Appendix C.

represent only a small fraction, less than one percent, of total NOx emissions in the Imperial Valley-Mexicali area. A simple extrapolation would indicate that the incremental increase in PM_{10} concentrations due to secondary formation from the power plant emissions is more than 30 times less than the 1.0 ug/m^3 figure yielded by the air modeling performed for the DEIS. Although the DEIS correctly concludes that the secondary formation of particulates from the power plants is "de minimis," the use of the Stockwell conversion factor and the resulting reference to a 1.0 ug/m^3 impact is highly misleading. It should be deleted from the final EIS and replaced with a more realistic analysis, based on the Chow and Watson study, to explain the conclusion that the secondary particulates attributable to emissions from the power plants have virtually no impact on ambient PM_{10} concentrations. 0018-6 (cont.)

e. Particulate Emissions from Exposed Salton Sea Lakebed. The DEIS notes that the reduced volume in the Salton Sea resulting from the power plant operations will have the effect of exposing a thin strip of land adjacent to the shoreline of the Salton Sea. The DEIS attempts to estimate the potential fugitive emissions of particulates caused by wind erosion of this exposed strip of lakebed by extrapolating from a study of fugitive dust emissions from the bed of Owens Lake, which has been completely dry since the late 1920s. See DEIS at 4-56. The DEIS concludes this analysis by stating that fugitive emissions of particulates from the exposed Salton Sea shoreline "could be estimated to be << 100tons/yr (<< 91 t/yr) as a result of the proposed action." Id. at 4-57. This statement gives the impression of a much larger potential impact than is supported by the analysis that precedes it. There is no basis for using a figure as large as 100 tons per year as the frame of reference for describing the magnitude of the potential fugitive particulate emissions from the Salton Sea shoreline. Two paragraphs earlier, the DEIS explains that a straight extrapolation from the Owens Lake study 0018-7

0018-7 (cont.)

would yield an estimate of only 50 tons per year. Moreover, the DEIS goes on to note that this 50 ton per year figure itself likely represents an overestimate because the amount of dust produced per acre from an expansive and long-dry lakebed would be significantly higher than the amount of dust produced from a seven foot wide strip of land adjacent to a large water body. A more appropriate conclusion to draw from the analysis in the DEIS is that fugitive emissions of particulates from the exposed edge of the Salton Sea are likely to be significantly less than 50 tons per year.

2. Environmental Significance of Power Plant Impacts

0018-8

The DEIS not only overstates the magnitude of the air emissions and water consumption resulting from the power plant operations attributable to the transmission line projects, but in several instances (as noted below) it also overstates the environmental significance of these power plant impacts. The final EIS should be more careful in stating its conclusions to ensure that they are properly supported by the underlying data and analysis and are stated consistently throughout the document.

0018-9

a. "Adverse" Air Impacts. In the discussion of "unavoidable adverse impacts," the DEIS states that it is "likely" that ozone "would be secondarily produced due to the operation of the two plants." DEIS at 6-2. This statement is not consistent with the analysis of air quality impacts earlier in the DEIS, which indicates that the modeling of NOx emissions from the power plants showed that the operation of the power plant is likely to result in a slight reduction in ozone concentrations. See DEIS at 4-51. Although this conclusion may seem surprising, it appears to be based on a sound scientific methodology and should be presented consistently throughout the document.

0018-10

b. MCLs as Water Quality Benchmarks. The DEIS uses EPA's published maximum contaminant levels ("MCLs") as a benchmark to evaluate the quality of the New River with respect to several constituents. DEIS at 3-15, 3-22. MCLs are standards for drinking water. The New River is not a viable source of drinking water due to adverse water quality conditions entirely unrelated to any operation of the power plants. The final EIS should make clear that use of MCLs to evaluate New River water quality is therefore highly conservative.

0018-11

c. Salton Sea Salinity Impacts. The DEIS states that "[g]iven the uncertainties related to the restoration activities at the Salton Sea, the long-term magnitude and significance of these impacts is difficult to quantify." In particular, the DEIS does not account for the effects of the Salton Sea Restoration Project in its analysis of cumulative impacts because the details of the project "are still under development." DEIS at 5-18. It appears, however, that the restoration activities may not be as uncertain as the DEIS indicates. According to the Environmental Assessment for the Mexicali II Wastewater Treatment Plant (one of the documents referenced in the DEIS), in April 2003, the Salton Sea Authority Board of Directors endorsed moving forward with the so-called "North Lake" plan to improve the Salton Sea. The plan involves "creating and managing an ocean-like lake in the North Basin of the Sea by constructing a dam mid-way across the current Sea. Extensive shallow water habitat would be created using stepped ponds in the South of the Sea. The plan also includes desalinization of Imperial Valley rivers." Even if the Restoration Project's potential improvements to the Salton Sea cannot currently be quantified, the final EIS at least should point out that the Restoration Project was tasked to consider a reduction in inflows to the Sea of 540,000 acre-ft/yr. The reduction in inflow to the Sea due to operation of the power plants is a small fraction of this amount. Thus, if the Restoration Project succeeds in achieving its objectives, on a cumulative basis the impacts of the proposed actions on the Salton Sea would be effectively eliminated.

0018-11 (cont.)

d. Brawley Wetlands. The summary section of the DEIS (which could be the only section of the report that many persons will read) states that "[i]ncreases in TDS and selenium concentrations could cause adverse impacts to the wetland system." DEIS at S-28. This conclusion is contrary to the analysis presented in the main body of the report. Although this same statement is repeated in Section 4.4.4.4.2, it is qualified immediately thereafter by the observation that the higher concentrations of TDS and selenium "should not exceed the tolerance of wetland plants, whereas the changes in the other water quality parameters could be beneficial." Id. at 4-25. The DEIS elsewhere states that "[i]t is also anticipated that the changes in water depth and water quality would not affect the ability to operate and maintain the Brawley wetland that has been constructed adjacent to the New River." Id. at 4-66. After discussing the negligible impacts of the increased TDS concentration on the specific plants in the Brawley wetland in the next paragraph, the DEIS goes on to state that "[t]he small change in salinity compared with the no action alternative and the small probability of exceeding salinity tolerances of the wetland plants indicate that implementing the proposed action using the wet cooling alternative is unlikely to affect the wetland area at Brawley." Id. Finally, further down on the same page, the DEIS notes that "[n]o data were available for selenium concentrations in sediments or water at the Brawley wetland; therefore, there was no evaluation of impacts to wetland vegetation. Since the total load of selenium to the New River is reduced by operation of the power plants, and flow rate reductions from power plant water use would

0018-12

not likely reduce water depth in the stretch of the river that supplies water to the Brawley wetland, adverse impacts to vegetation are not expected." Id.

0018-12 (cont.)

D. The analysis of the "technology" and "mitigation" alternatives should focus only the impacts actually resulting from the transmission line projects, and should consider more critically the technical feasibility and cost-effectiveness of these alternatives.

1. Alternative Technologies

The DEIS considers two kinds of alternative technologies to reduce environmental impacts from the operation of the power plants -- oxidizing catalysts to limit emission of carbon monoxide ("CO") and some form of dry cooling to reduce the consumption of water. The analysis of these alternatives in the final EIS should be modified in several respects. First, and perhaps most important, the discussion in the DEIS is almost entirely theoretical. The district court precluded the Agencies from considering the fact the transmission lines have been built and are operating, but it did not preclude the Agencies from considering the fact that the Mexican power plants have been built and have commenced commercial operations. See DEIS at A-79. Nonetheless, the DEIS describes the use of these alternative technologies in general terms as if the TDM and EBC plants were still in the design phase and the issue were simply whether these technologies could be worked into the design.[6] Rather, the technical feasibility, costs, and effectiveness of these technologies must be considered in the context of a retrofit to an existing plant. A retrofit presents additional technical and practical challenges, and additional costs (including the opportunity cost of down time for the physical installation.) The

0018-13

[6] The DEIS generally describes the power plants as if they had not yet been built. See, e.g., DEIS at 2-28 ("All generating units at both power plants would operate in a combined cycle mode and would be fueled by natural gas . . . .") (emphasis added). As noted, this approach is not required by the district court's remedy ruling and may be misleading to readers of the document. The final EIS should acknowledge that that the plants have been constructed and have commenced operation.

0018-13 (cont.)

analysis needs to address issues such as whether the existing designs can physically accommodate a retrofit -- i.e., is there is enough space to install oxidizing catalyst equipment or enough properly situated land to accommodate the dry cooling equipment? -- and how a retrofit may affect vendor guarantees for the other equipment at the plant that are critical to the financing of the projects. The final EIS also should include information as to the likely costs of a retrofit installation of the technologies under consideration to give the public and the agency decision makers a basis on which to judge the cost effectiveness of such measures.

In particular, contrary to the suggestion of some commenters, the retrofit of a dry or parallel wet-dry cooling system at the LRPC would present major technical problems and would entail very significant costs. Parallel wet-dry cooling is not a proven retrofit technology. Such a system has been installed as a retrofit on only a single plant in the United States -- the 37 MW Streeter plant in Cedar Falls, Iowa. This facility does not provide a model for the retrofit of parallel wet-dry cooling at the LRPC. The dry tower required for the Streeter plant was relatively small due to the modest generating capacity of the plant and because the cooling system requirements were less demanding given the appreciably colder climate compared to Mexicali. Several acres of dry cooling towers would be required for the LRPC. These structures would need to be located close to the generating facilities where their performance would be negatively affected by the vagaries of the wind, and their interaction with the plant buildings, neither of which factors could have been considered as part of the original plant design. See Letter Report from Burns Engineering, Inc., "Retrofitting a Parallel Wet-Dry Cooling System to the La Rosita Power Complex," July 29, 2004, at 5.[7] In addition, the cost to retrofit a parallel wet-dry cooling system -- which include not just the initial capital costs, but

[7] A copy of this report is attached to these comments as Appendix D.

13

0018-13 (cont.)

also the costs for engineering and design work, the cost of lost power sales during down time required for the installation, and the ongoing additional operation and maintenance costs (including the energy penalty associated with less efficient air cooling) -- are likely far higher than projected by some commenters. See id. at 4.

Second, the discussion of the environmental consequences of the alternative technologies should provide a proper context for evaluating whether the actual benefits of these technologies could possibly warrant the significant costs and uncertainties of attempting to employ them. Moreover, such discussion must focus on the TDM and EBC plants alone (or in the case of CO catalyst, just the EBC plant), as they are the only ones where the use of such technologies might be induced by means of a condition on the transmission line permits. For example, the discussion of CO catalyst in Section 4.3.5.1 of the DEIS simply refers to table 4.3-4 for information regarding potential CO reductions. DEIS at 4-57. Table 4.3-4 shows the reduction in CO assuming the use of oxidizing catalyst at all four LRPC turbines, rather than just the EBC plant. Even then, what the table shows -- and what should be stated expressly in the text as well -- is that effect of CO emissions from the power plants on ambient CO are already so small (less than 1% of the significance level) that there would be no justification for devoting additional resources to reduce these already negligible impacts.

The same is true with respect to the use of dry cooling (or wet-dry cooling) to reduce water consumption. The DEIS states that the impacts to the Salton Sea from dry cooling system would be "much less" than those estimated for the proposed action, and refers the reader to Table 4.2-7. DEIS at 4-26. This statement creates the erroneous impression that the use of dry cooling could produce significant environmental benefits in terms of water quality. As noted above, Table 4.2-7 does not even show the proper "proposed action" scenario -- the

14